USC University of Southern California

PTE555 Final Project Report (Summer 2022)

Optimization of hydraulic fracturing design in unconventional formation: comparative of study of fracking fluids

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Abstract

Horizontal well technology coupled with multistage hydraulic fracturing enabled economic production from unconventional reservoirs. However, even with application of those advanced technologies, the recovery from these reservoirs is far from optimal. Major reasons for suboptimal reservoir recovery are high levels of reservoir heterogeneity and non-optimal hydraulic fracture jobs. The objective of this study is to address the suboptimal hydraulic fracture design problem. Hydraulic fracturing optimization is a wide topic and there are different mechanisms in a play and a range of design variables to consider and optimize. High resolution modeling studies are one of the tools that enabled understanding of the mechanism of hydraulic fracturing and improving treatment designs. In this work, state of art hydraulic fracturing simulator is used to model the hydraulic fracture propagation in a field-like unconventional model with one horizontal well. Comparative study using three different fracturing fluids, namely slickwater, linear and cross-link gel, is done to select the best fracturing fluid and optimize hydraulic fracturing job. Results show that fractures created by cross link gel fracking fluid led to largest length distributions, propped and total fracked areas, followed by linear gel and slickwater.

Introduction

Since the first field trial on a gas well in 1947 in Oklahoma, hyfraulic fracturing as a technology has been extensively researched by people both in academia and industry using combination of field, experimental and numerical simulation studies (King GE, 2010). Simulation of hydraulic fracturing technology, as a tool to fracture rock formations, using a combination of fluid at high pressure and proppant has been applied for a long time and for different purposes, ranging from estimation of stress variations to caving and fault reactivation studies (Adachi J et al., 2007; He Q et al., 2016; Murdoch LC, 2002). Production from shale reservoirs has seen a significant improvement after the use of extensive modeling studies (Davies RJ et al., 2012).

Fundamentally, hydraulic fracturing process includes three processes, namely fracture initiation, fracture propagation and flow-back. The final fracture network is affected by a range of design variables pre-defined before conducting fracturing job. Among the most important variables are proppant, fracking fluid type, properties and amount, perforation cluster density, reservoir rock geomechanical properties and in-situ stress. The complexity of resulting hydraulic fracture network is a function of the listed parameter values and their interactions. Usually, to make the modeling study tractable and pragmatic to field applications, only fundamental affecting mechanisms are included to the propagation models, some aspects of the problems are simplified and some of effects having negligible effect on end results are ignored.

Extensive study of hydraulic fracture propagation process, between 1950s and 1980s led to the development of fundamental hydraulic fracture propagation models that are still in wide use today. Currently, existing hydraulic fracture models are classified as 1) 2D/classic fracture propagation models, such as Kristianovich-Geertsma-de Klerk (KGD) model and the Perkins-Kern-Nordgren (PKN) model, 2) pseudo 3D (P3D) model and 3) planar 3D (PL3D) model (Weng X et al., 2014). These models differ by the underlying assumptions used during the development of models and level of complexity and detail involved.

In this study, Unconventional Fracture Model (UFM) (O Kresse et al., 2013), which is pseudo 3D model, is used to model the hydraulic fracture propagation. UFM model is the only computationally tractable hydraulic fracture model that incorporates the interaction between natural and hydraulic fractures. Fracking fluid is selected as a design variable for optimization of hydraulic fracturing job. Concretely, the performances of slickwater, linear and cross-link gel fracking fluids are compared to select the best fluid with the goal to optimize the hydraulic fracturing job.

Reservoir modeling

The study is performed on a field-scale unconventional reservoir model with one horizontal well, built using Petrel. Reservoir architecture and distribution of natural fractures is shown in Figures 1 and 2. Some key reservoir information is summarized below:

1. Structure (rectangular, no faults, 4 horizontal layers):

- **Model dimension and discretization:** 6000 ft x 3000 ft x 500 ft. Grid: 200 (dx=30 ft) x 100 (dy=30 ft) x 50 (dz=10 ft)
- **Layering:** 4 layers (150 ft each, 10600-11200 ft), Layer 2 &3 – pay zone, Layer 1 & 4 non-pay

2. Facies and properties:

- **Facies:** Layer 1, 4: non-pay (por:4%, perm: 0.0001 mD, Sw:0.9), Layer 2, 3: pay (por: 8%, perm: 0.001 mD, Sw:0.4)
- **Well logs:** synthetic, with binary values for pay/non pay: GR, por_mat, perm_mat por_NF, perm_NF, sonic

3. Wells – 1 horizontal well:

- **Lateral section:** 3300 ft; penetrates layer 2

4. Discrete fracture network (DFN) parameters:

- **Length: mean: 150 m, std: 40 m; Orientation: mean: 120, std: 20 m; Spacing: mean: 80 m, std: 40 m**

5. Geomechanical inputs:

- **Pore Pressure:** L1: 8600 psi - 0.85 psi/ft, L2, 8700 psi – 0.8 psi/ft, L3 8800 psi – 0.8 psi/ft, L4 8900 – 0.85 psi/ft
- **Overburden pressure:** L1: 11000 psi, L2: 11150 psi, L3: 11300 psi, L4: 11450 psi
- **Stresses:** Shmin (NW 36) –Shmax (NE 57): L1: 9000-9800 psi, L2 9150-9980 psi , L3 9300-10150 psi, L4 9450-10250 psi
- **Rock properties:** Young’s modulus, Poisson, rock compressibility

6. Hydraulic fracture design parameters:

- **Staging**: 10 stages, stage spacing: 80 ft, stage length: 250 ft
- **Perforation clusters**: 8 clusters, spacing: 30 ft, shot density: 6 shot/ft
- **Proppant**: Badger sand 20/40
- **Fracking fluids**: Case 1: Slickwater, Case 2: Linear gel, Case 3: Cross link gel

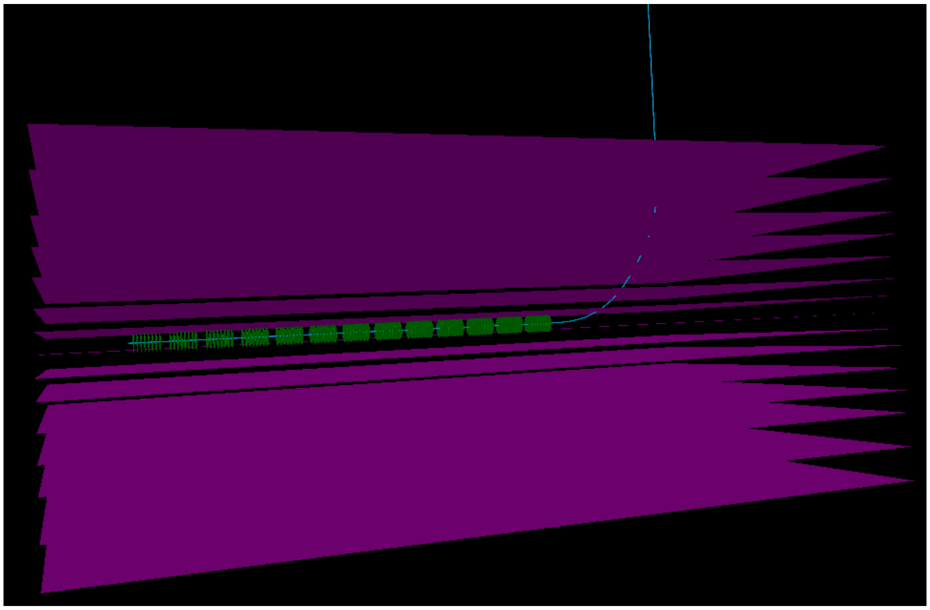

Figure 1. Reservoir architecture, layers and well

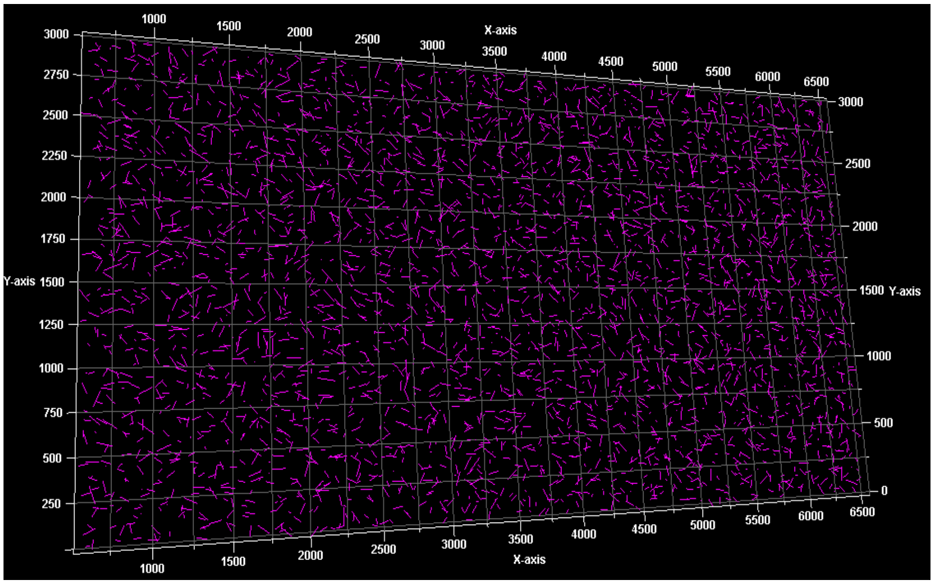

Figure 2. Natural fracture distribution in the field

Same pump schedule has been applied to all 10 fracturing stages (Figure 3). The only parameter that was varied among 3 cases is fracking fluid.

	Step name	Pump rate (bbl/min)	Fluid name	Fluid volume (gal)	Proppant	Prop. conc (PPA)	Prop. mass (lb)	Slurry volume (bbl)	Pump time (min)	Step type
1	Pad	20.00	YF125-Flex - M...	10000.00	None	0.00	0.00	238.10	11.90	Pad
2	Pad	20.00	YF125-Flex - M...	10000.00	None	0.00	0.00	238.10	11.90	Pad
3	Pad	20.00	YF125-Flex - M...	10000.00	None	0.00	0.00	238.10	11.90	Pad
4	0.5 PPA	20.00	YF125-Flex - M...	10000.00	Badger Sand 20/40	0.50	5000.00	243.49	12.17	Slurry
5	0.75 P...	20.00	YF125-Flex - M...	10000.00	Badger Sand 20/40	0.75	7500.00	246.19	12.31	Slurry
6	1 PPA	20.00	YF125-Flex - M...	10000.00	Badger Sand 20/40	1.00	10000.00	248.89	12.44	Slurry
7	1.5 PPA	20.00	YF125-Flex - M...	10000.00	Badger Sand 20/40	1.50	15000.00	254.29	12.71	Slurry
8	2 PPA	20.00	YF125-Flex - M...	10000.00	Badger Sand 20/40	2.00	20000.00	259.69	12.98	Slurry
9	2.5 PPA	20.00	YF125-Flex - M...	10000.00	Badger Sand 20/40	2.50	25000.00	265.09	13.25	Slurry
10	3 PPA	20.00	YF125-Flex - M...	10000.00	Badger Sand 20/40	3.00	30000.00	270.49	13.52	Slurry
11	3.5 PPA	20.00	YF125-Flex - M...	10000.00	Badger Sand 20/40	3.50	35000.00	275.89	13.79	Slurry
12	4 PPA	20.00	YF125-Flex - M...	10000.00	Badger Sand 20/40	4.00	40000.00	281.29	14.06	Slurry
13	4.5 PPA	20.00	YF125-Flex - M...	10000.00	Badger Sand 20/40	4.50	45000.00	286.69	14.33	Slurry
14	5 PPA	20.00	YF125-Flex - M...	10000.00	Badger Sand 20/40	5.00	50000.00	292.09	14.60	Slurry

Figure 3. Pump schedule for all stages

The performances of 3 different fracking fluids are compared in this study. These fracking fluids differ among each other mainly by the viscosity values. Figure 4 shows the viscosity curve for all 3 fluids. Cross link gel has their highest viscosity values, followed by linear gel and slickwater.

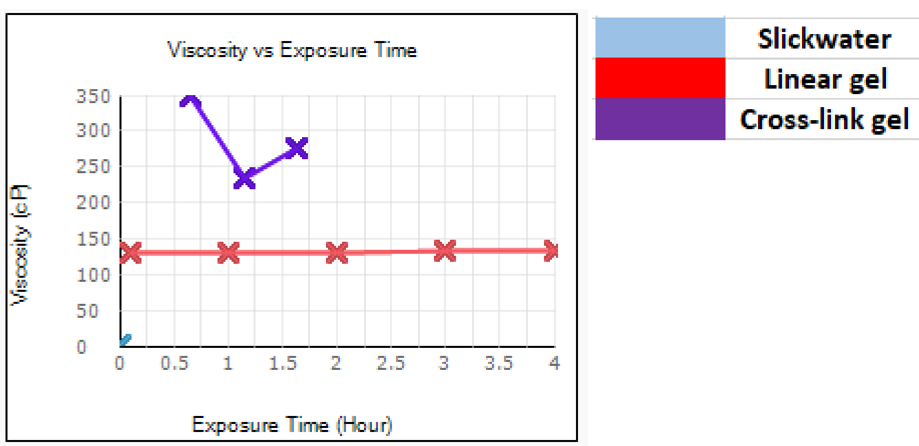

Figure 4. Viscosity evolution through time for 3 fracking fluids

Results and discussion

Case 1: Slickwater

In this case, the slickwater is used as a fracking fluid for all the stages. The modeling results are shown in Figure 4.

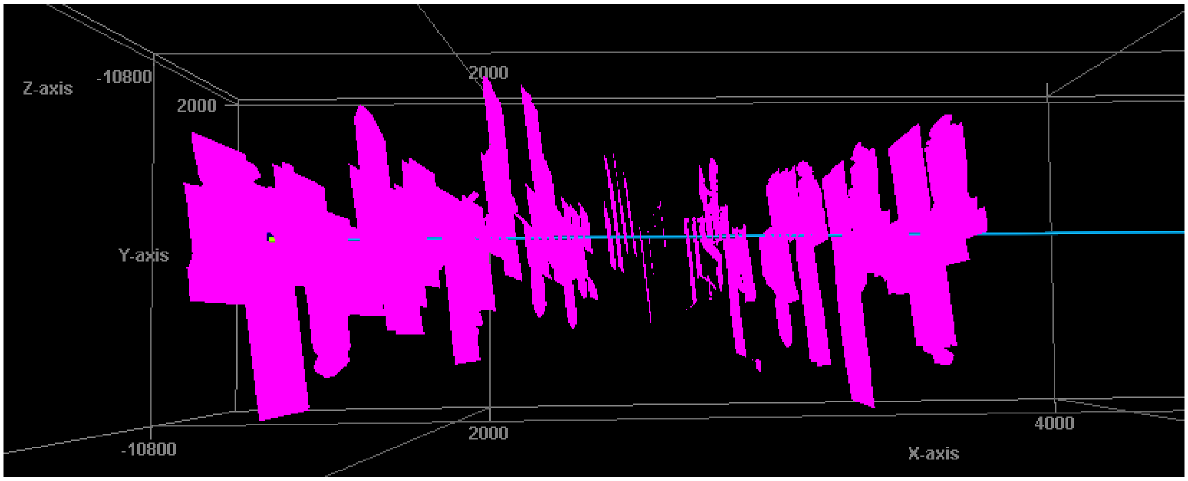

Figure 5. Fracture distribution for case 1

Case 2: Linear gel

In this case, the linear gel is used as a fracking fluid for all the stages. The modeling results are shown in Figure 5.

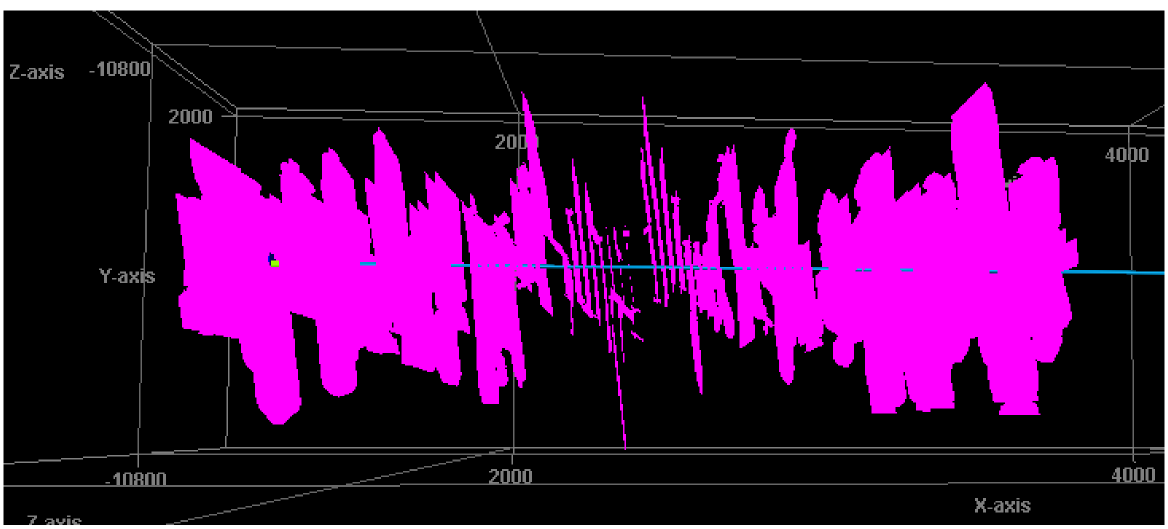

Figure 6. Fracture distribution for case 2

Case 3: Cross-link gel

In this case, the cross-link gel is used as a fracking fluid for all the stages. The modeling results are shown in Figure 6.

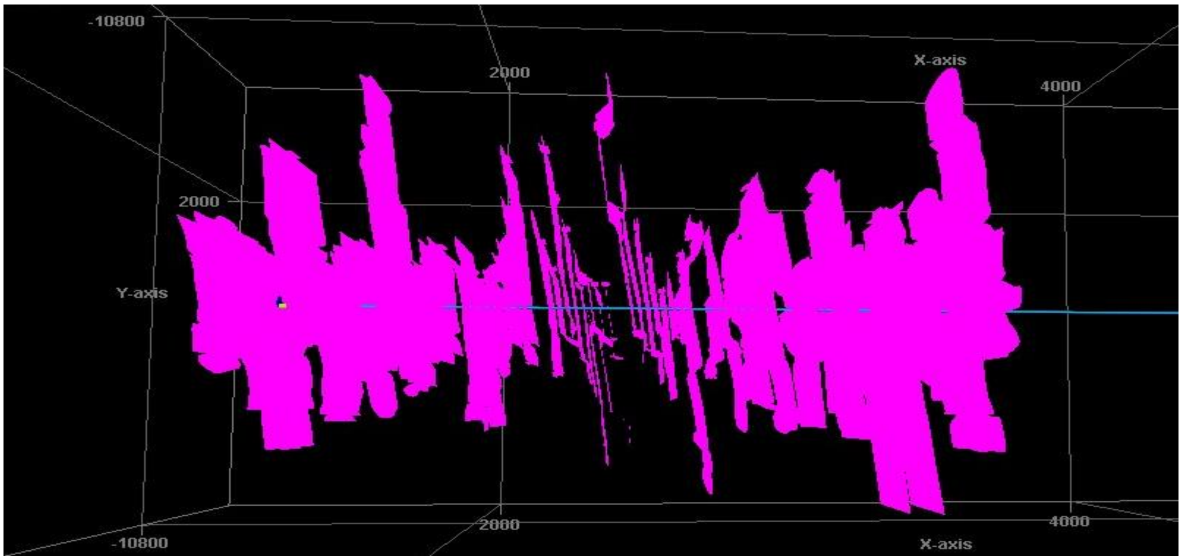

Figure 7. Fracture distribution for case 3

Hydraulic fracture geometry comparison among 3 cases

Generally, slickwater is applicable where drag reduction and less-complex fluid systems are desired (Schlumberger). Linear gel offers improved proppant transport characteristics (Schlumberger). Cross-linked gel fracking fluid not only maintains all the advantages of the mentioned fluids but also creates wider fractures to enable high proppant concentrations and generate high fracture conductivity (Schlumberger). From fracture distribution figures (Figure 5, 6, 7), it is apparent that there is a noticeable discrepancy between fracture geometries among 3 cases. Generally, lower viscosity fracking fluids, such as slickwater have lower proppant transport carrying capacity and is lost more to the reservoir, leading to less efficient fracking job and closure of fractures once the pumping is stopped.

According to figures 8, 9, 10 the use of cross-link gel leads to highest total and propped fracture surface areas, followed by linear gel and slickwater. Compared to fracture surface area values among cases, there is less discrepancy in fracture length distributions among cases. Fractures generated by cross link gel, generally, have higher lengths compared to linear gel and slickwater. Fracture length distributions generated by linear gel and slickwater show similar distributions, with linear gel generated fracs exhibiting more uniform distribution.

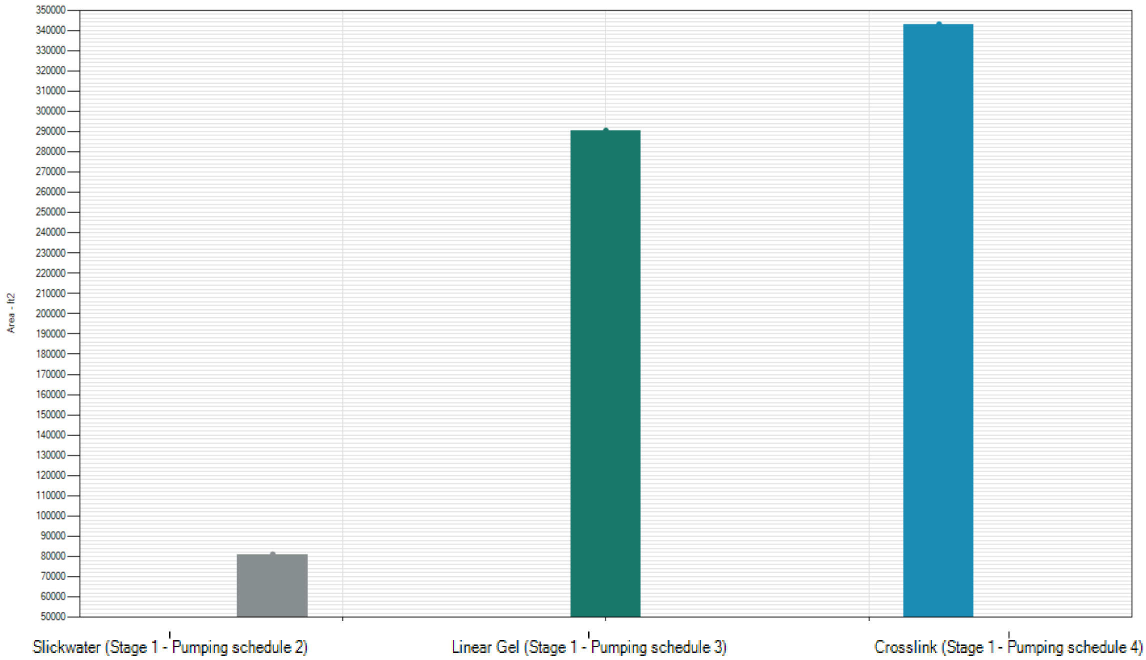

Figure 8. Propped fracture surface areas for 3 cases

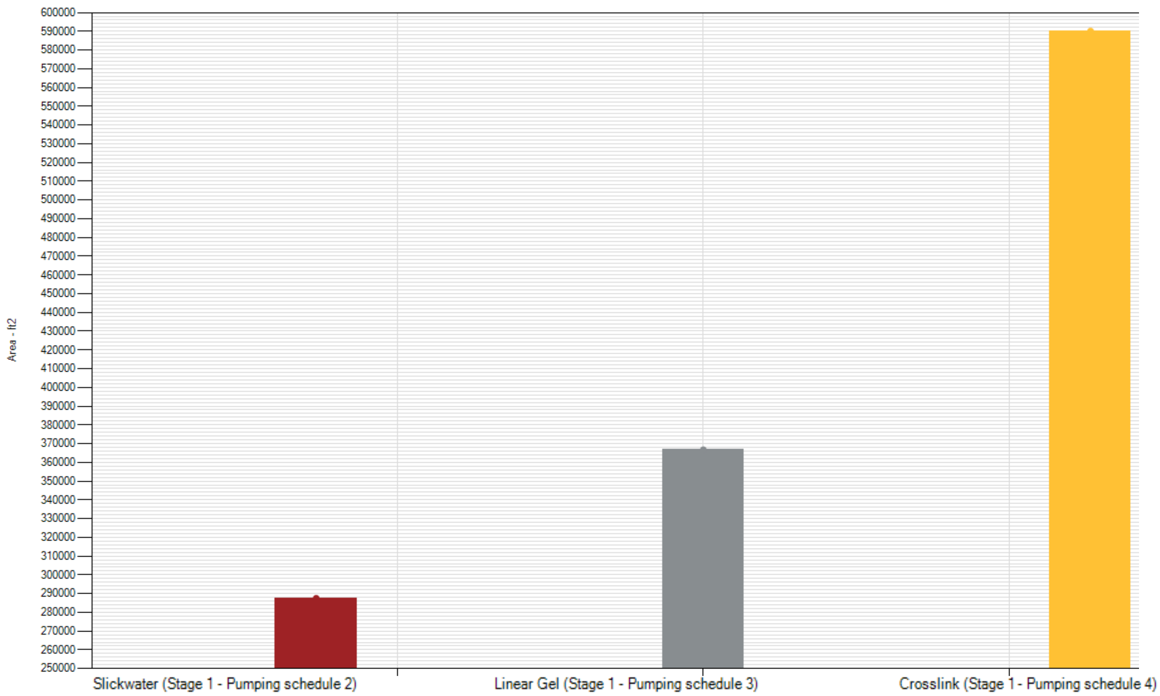

Figure 9. Total fracture surface areas for 3 cases

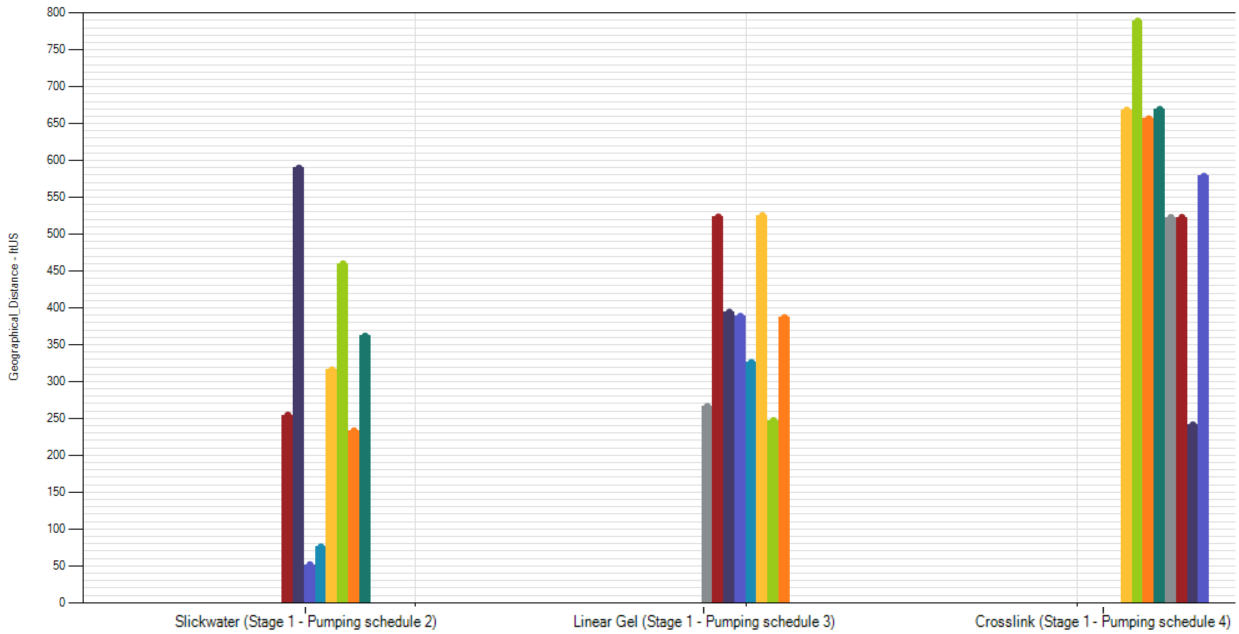

Figure 10. Fracture length distribution for 3 cases

Conclusion

In this work, comparative study using three different fracturing fluids is used for hydraulic fracture design optimization. As expected, results show that the use of cross-link gel leads to highest total and propped fracture surface areas, followed by linear gel and slickwater. Although, the discrepancy is less pronounced, fractures generated by cross link gel, generally, have higher lengths compared to linear gel and slickwater. Fracture length distributions generated by linear gel and slickwater show similar distributions, with linear gel generated fracs exhibiting more uniform distribution. As a future work, flow simulation of generated fracture networks using these fracking fluids can be done to compare dynamic flow responses of cases.

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